Integrated API Gravity Tracking and Compositional Grading for Dynamic Reservoir Fluid Contact Monitoring in the Niger Delta

PROF. GODWIN CHUKWUMA NMEGBU[1], PROF. E.O EHIRIM[2], IDONIBOYE ROLAND OBOMATE[3], DEXTERITY CLIFFORD[4]

[1,3,4]Department of Petroleum Engineering, Rivers State University, Nigeria
[2]Department of Petrochemical Engineering, Rivers State University, Nigeria

Abstract- Accurate monitoring of reservoir fluid contacts is critical for effective hydrocarbon recovery and reservoir management, particularly in complex and compartmentalized formations such as those of the Niger Delta Basin. Traditional approaches for determining gas–oil and oil–water contacts, including pressure gradient interpretation and repeat formation testing, are costly and require well shut-ins. This study presents an integrated methodology combining API gravity tracking and compositional grading as cost-effective alternatives for monitoring reservoir fluid contact movement. The research incorporates well log interpretation, PVT laboratory data, compositional reservoir simulation (ECLIPSE 100), and comparative analysis with conventional techniques. Results from representative Niger Delta reservoirs show a systematic decrease in API gravity with depth (32° to 28° API between 2,500–2,800 m), confirming gravitational segregation effects. Fields exhibiting higher gas–oil ratios demonstrated improved API values, whereas increasing water cut corresponded with declining API gravity. The integration of compositional grading models with API monitoring provides a thermodynamically consistent and empirically validated workflow for predicting contact migration and improving reserves estimation accuracy. The proposed methodology significantly reduces reliance on costly logging interventions and offers a scalable surveillance solution for both onshore and offshore Niger Delta fields.

Index Terms- API gravity tracking, compositional grading, reservoir simulation, fluid contact monitoring gas-oil contact, oil-water contact.

I. INTRODUCTION

Reservoir fluid contact identification plays a critical role in reserves estimation, well placement, and production optimization. Conventional techniques such as repeat formation testing (RFT), modular dynamic testing (MDT), resistivity interpretation, and pressure gradient analysis are widely used but are operationally expensive and often require well shut-ins.

In heterogeneous reservoirs such as those of the Niger Delta Basin, faulting and compartmentalization further complicate contact determination. Compositional grading theory suggests that hydrocarbon mixtures in gravitational equilibrium exhibit vertical variation in composition and density. API gravity, being directly related to density, can therefore serve as a measurable proxy for compositional variation and fluid contact position.

This study investigates the integration of API tracking within compositional simulation workflows to provide dynamic and cost-effective fluid contact monitoring.

II. GEOLOGICAL SETTING: NIGER DELTA BASIN

The Niger Delta Basin is a prolific Cenozoic petroleum province characterized by:

- Akata Formation (source rock)
- Agbada Formation (primary reservoir)
- Benin Formation (overburden)

Reservoirs are structurally controlled by growth faults and rollover anticlines, resulting in stacked and compartmentalized sand bodies with active aquifer support and gas cap expansion mechanisms.

III. THEORETICAL FRAMEWORK

3.1 Compositional Grading

Under gravitational equilibrium, the chemical potential of each hydrocarbon component varies with depth. Heavier molecules concentrate at lower structural elevations, producing measurable gradients in:

- Molecular weight
- Density
- API gravity
- Saturation pressure

This phenomenon becomes pronounced in volatile oil and near-critical systems.

3.2 API Gravity as a Proxy Parameter

API gravity is defined as:

$$API = \frac{141.5}{SG_{60°F}} - 131.5$$

Variations in API gravity reflect compositional redistribution and can therefore indicate fluid contact movement.

IV. METHODOLOGY

The workflow adopted includes:

1. Well log interpretation (density, resistivity, NMR)
2. PVT laboratory analysis
3. EOS characterization (Peng–Robinson)
4. Initialization of compositional reservoir model (ECLIPSE 100)
5. Activation of API tracking module
6. Simulation of pressure depletion and contact migration
7. Comparison with conventional contact estimation methods

V. RESULTS

5.1 Reservoir Properties and Fluid Characteristics

Table 5.1 presents the API tracking, compositional grading and fluid contact movement; showing the samples 1-4 at depth ranging from 2,500m to 2,800m with their corresponding API values and oil gravity in kg/m3 alongside their gas compositions in percentage.

Table 5.1: API Tracking and Compositional Grading Data

Sample ID	Depth (m)	API Gravity (°API)	Oil Density (kg/m³)	Gas Composition (%)
S1	2,500	32	850	80 CH_4, 10 C_2H_6, 10 C_3H_8
S2	2,600	31	860	78 CH_4, 12 C_2H_6, 10 C_3H_8
S3	2,700	30	870	76 CH_4, 13 C_2H_6, 11 C_3H_8
S4	2,800	28	880	74 CH_4, 14 C_2H_6, 12 C_3H_8

Table 5.2 presents the fluid contact movement; showing the fields at various depth ranging from 2,650m to 3,480m with their corresponding contact depth and rate of movement.

Table 5.2: Fluid Contact Movement

Field Name	Monitoring Period (Years)	Initial Contact Depth (m)	Current Contact Depth (m)	Rate of Movement (m/year)
Field A	5	2,600	2,650	10
Field B	4	3,000	3,050	12.5
Field C	6	2,750	2,780	5
Field D	7	3,400	3,480	11.4

Table 5.3: Reservoir Fluid Properties for Prediction Model

Parameter	**Unit**	**Min Value**	**Max Value**	**Average**
API Gravity	°API	28	35	31.25
Oil Density	kg/m³	850	880	865
GOR	scf/stb	600	850	725
Water Saturation	%	20	35	27.5
Permeability	mD	180	300	237.5

Table 5.4: API Gravity Variations Across Selected Niger Delta Reservoirs

Field Name	Reservoir Depth (m TVDSS)	API Gravity (°API)	Gas-Oil Ratio (GOR) (scf/stb)	Oil Viscosity (cp)	Fluid Contact Movement (per year)
Field A (Offshore, Deepwater)	1,200 - 2,500	40° (shallow) → 28° (deep)	1,200 - 1,500	1.8 - 3.2	Slow (5-10 m shift)
Field B (Offshore, Deepwater)	1,400 - 2,800	42° (top) → 30° (bottom)	1,000 - 1,400	2.0 - 4.5	Moderate (10-15 m shift)
Field C (Onshore, Shallow Water)	800 - 2,000	50° (gas cap) → 20° (deep oil)	500 - 1,000	5.0 - 10.0	Fast (20-30 m shift)
Field D (Onshore, Swamp)	700 - 1,800	38° (upper) → 25° (lower)	600 - 1,100	3.5 - 6.8	Moderate (15-20 m shift)

5.2 Initial Pressure Distribution and Initial Oil and Water Saturation

Figures 5.1 and 5.2 shows the initial pressure distribution and oil saturation of the reservoir against depth. The plot shows that a high water cut well penetrating through a reservoir that has an OWC and good vertical permeability, over a period of time, the bottom water will begin to rise until it gets to the deepest perforation. At that point, water will break into the well bore. On breakthrough in reservoirs that have compositional variation with depth, the heavier ends will begin segregate from the lighter ends as a result of gravity. This will then lead to an increase in production of the heavier ends due to the sweeping action of the bottom water. This increase in production will also lead to a decrease in the surface API because of reduced dissolved gas or lower quantity of lighter ends hydrocarbon.

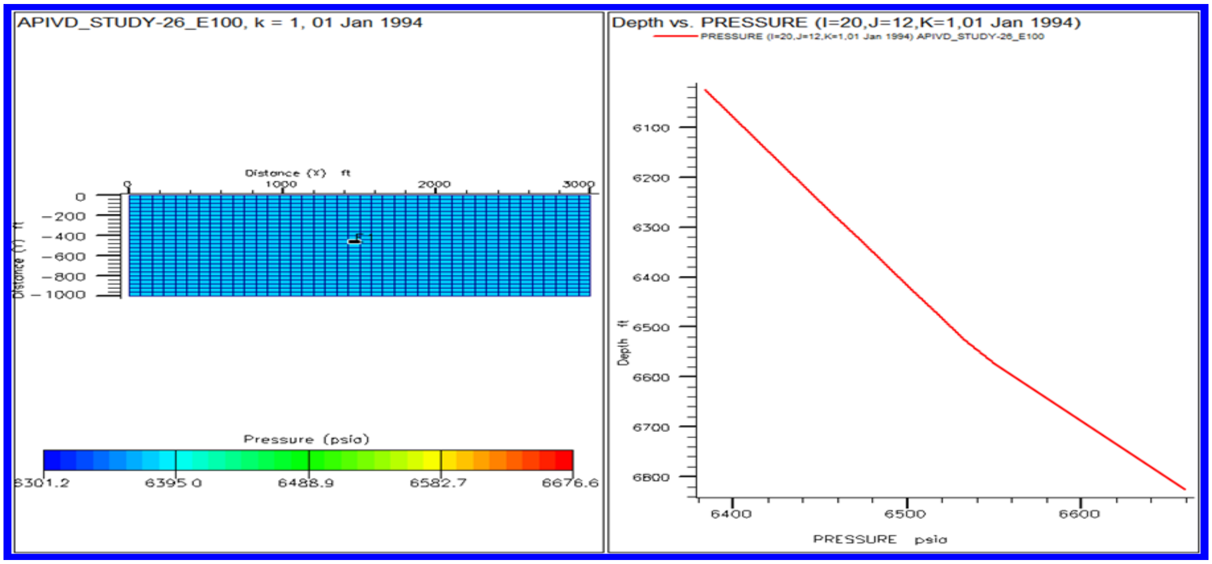

Figure 5.1: Initial Pressure distribution of the reservoir against depth

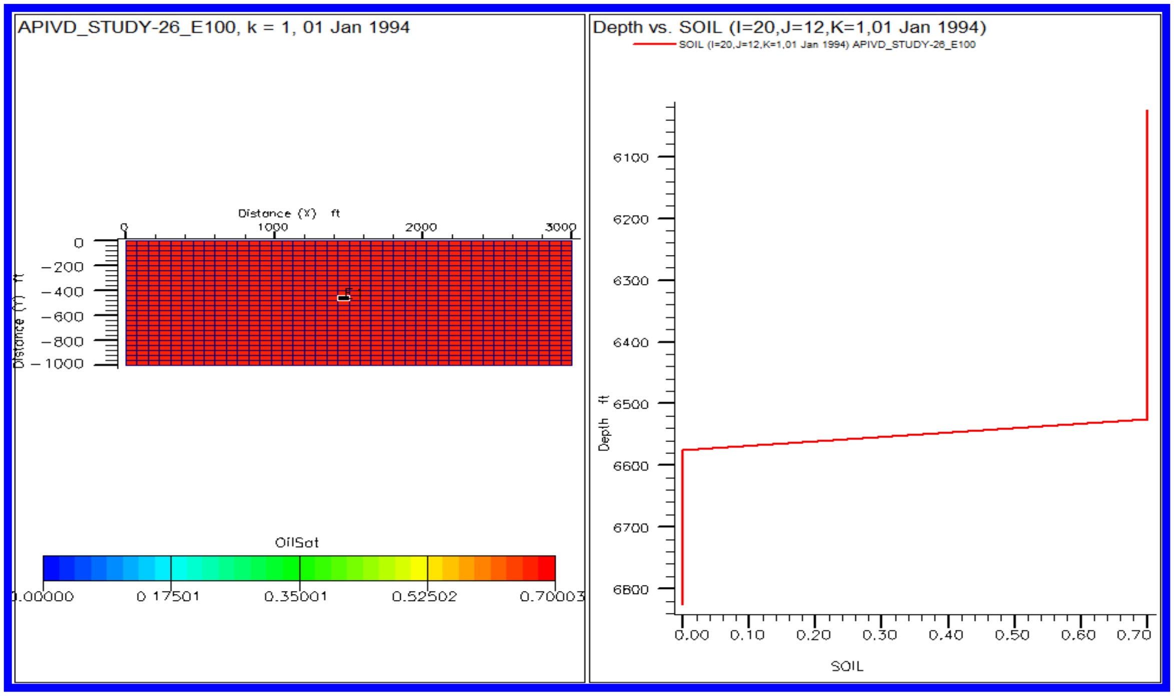

Figure 5.2: Initial oil saturation distribution of the reservoir against depth

From figure 5.3, the Reservoir model was defined using an initial OWC and changes in the API as a result of an increase in the water cut over time, the conceptual reservoir model is seen to have a GOC and OWC at the time of initialization. The change in API is as a result of an exponential increase in the GOR as studied.

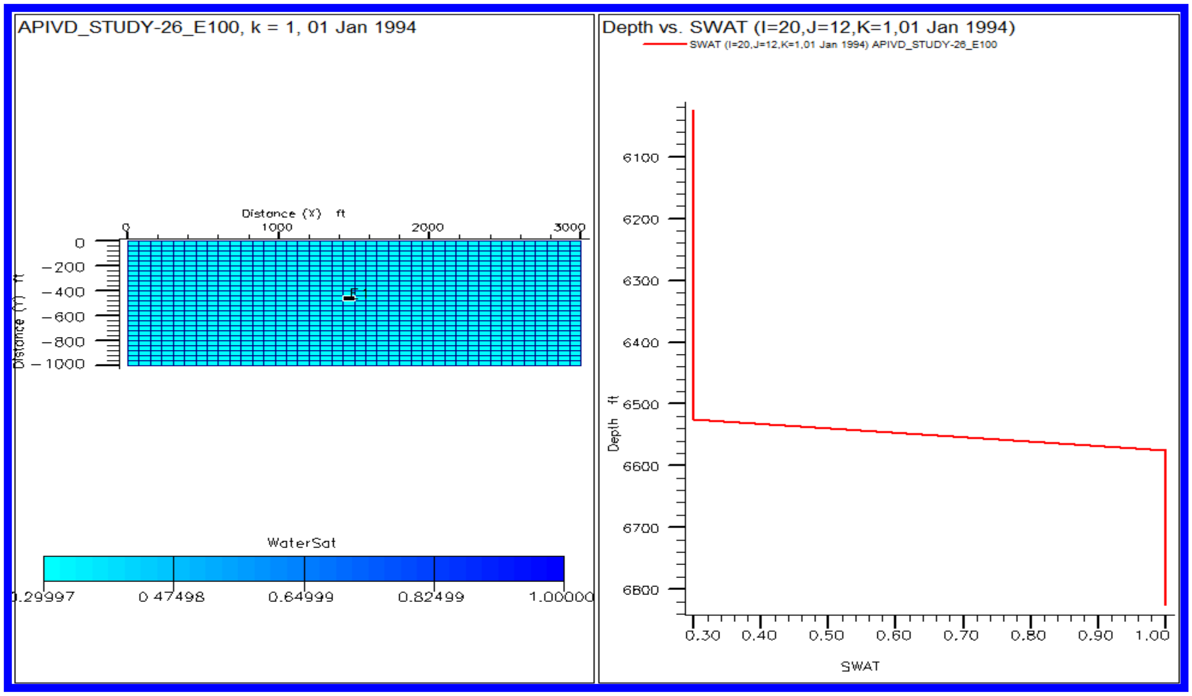

Figure 5.3: Initial water saturation distribution of the reservoir against depth

5.3 Fluid Contact Movement Analysis

5.3.1 Predictive Model using historical API gravity and compositional grading data.

An optimized approach was deployed after fitting more than 100 data points from historical API gravity tracking and compositional grading results as an input data in the eclipse 100 software to generate a regression equation which can predict the fluid contact movement with respect to depth. The plots below from figures 4.4 to 4.19 best explains the processes involved yielding a best fit for the model.

Figure 4.4 describes the water/oil saturation function plot which indicate the end point saturation and relative permeability points of the rock.

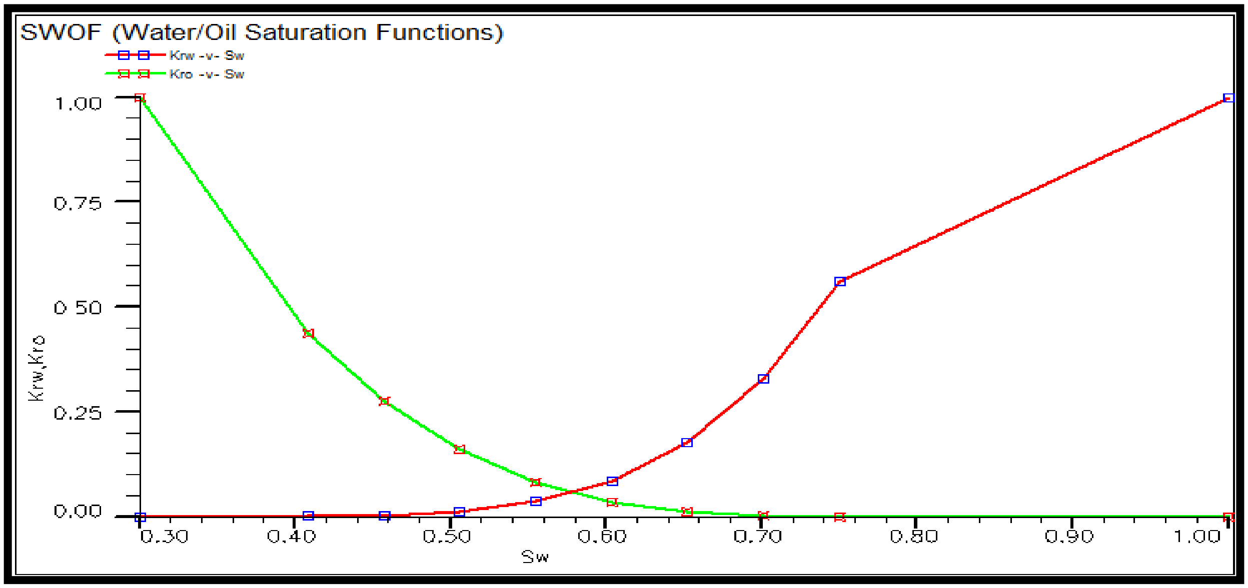

Figure 5.4: Water/oil saturation function

Figure 5.5 shows the Gas-Oil saturation function with respect to depth as shown

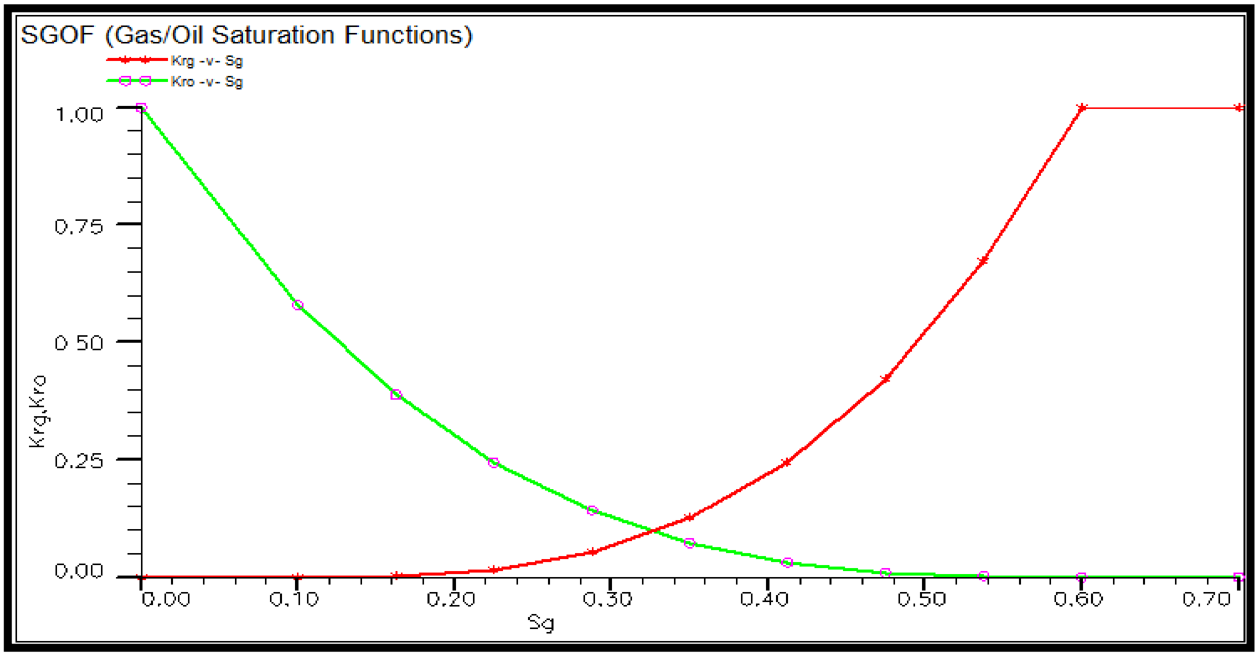

Figure 5.5: Gas/Oil saturation Function

Figure 5.6 shows the oil production rate is seen to be on a decline as the watercut increases. The reservoir pressure is also seen to be increasing slightly once water breakthrough occurs.

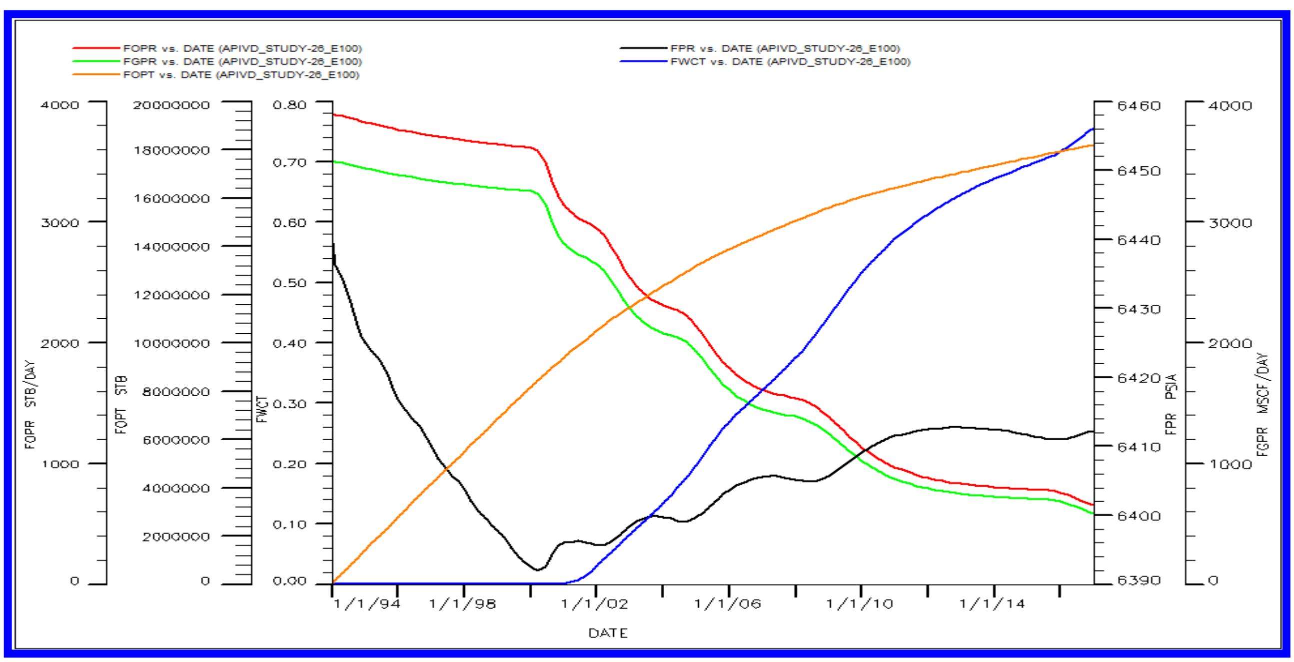

Figure 5.6: Production Profile Plot of the model

Figure 5.7 indicates the initial variation of the API with depth. From the plot, one could see that the API decreases with increase in depth. This is due to gravity. As a result of production, there will be an increase in production of bottom water leading to a change in the API.

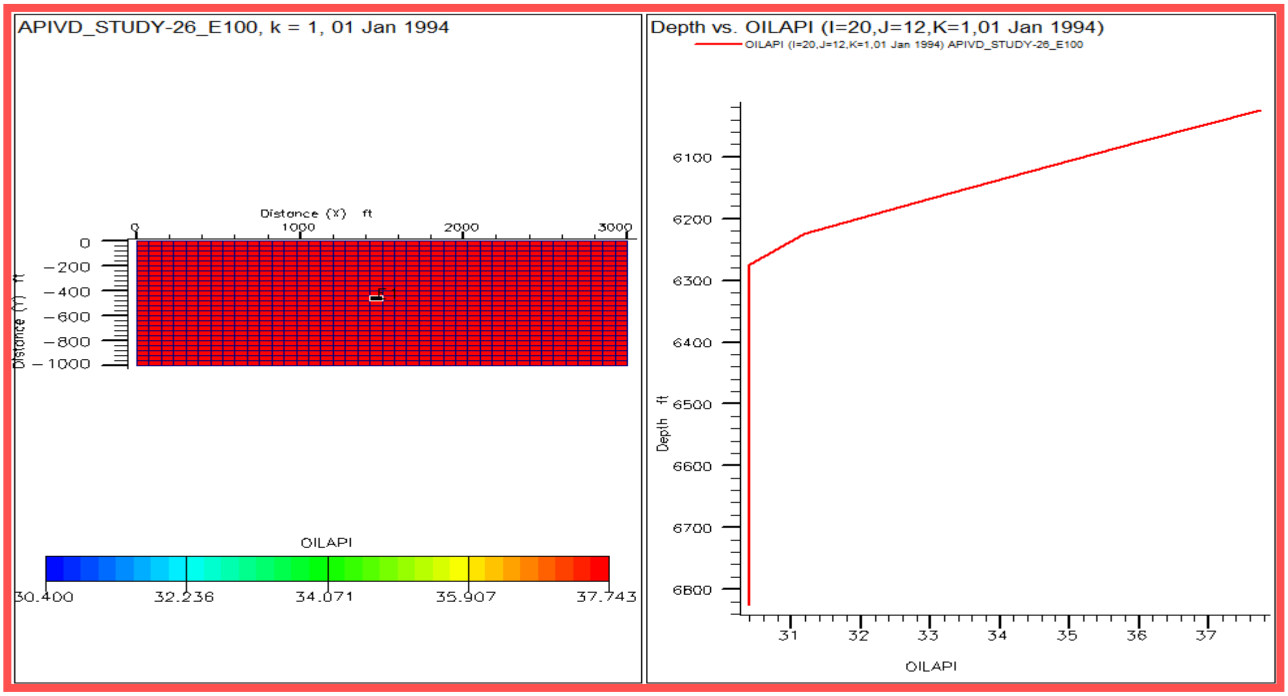

Figure 5.7: API Profile Plot of the model

5.4 Model Development

The predictive model developed uses historical API gravity, compositional grading, pressure, temperature, and time-based data to forecast fluid contact depth changes. It employs linear regression to establish relationships between these variables using Eclipse 100 software.

The actual predictive model for fluid contact movement is a multiple linear regression model, represented mathematically as:

$$FCD = \beta0 + \beta1 \cdot API + \beta2 \cdot CG + \beta3 \cdot P + \beta4 \cdot T + \beta5 \cdot t + \epsilon \quad (5.1)$$

Where:

FCD = Fluid Contact Depth (target variable)

API = API Gravity of the reservoir fluid

CG = Compositional Grading factor

P = Reservoir Pressure

T = Reservoir Temperature

t = Time (monitoring interval)

β0 = Intercept of the model

β1, β2, β3, β4, β5 = Regression coefficients (determined from training data)

ϵ = Error term

The model is trained using historical well log data, production records, and laboratory analysis, allowing it to estimate the position of fluid contact over time.

Key findings include:

- API gravity decreased from 32° to 28° with depth.
- Field C (20% water saturation) recorded highest API (35°).
- Field B exhibited highest contact movement rate (12.5 m/year).
- Gas cap expansion correlated with upward GOC migration.
- Increasing water cut corresponded to declining API gravity.

Simulation-based API tracking closely matched estimates from material balance and limited pressure data.

VI. DISCUSSION

The results confirm that API gravity tracking provides a reliable proxy for monitoring compositional redistribution and contact movement. Compared to RFT/MDT operations, the method:

- Eliminates shut-in requirements
- Enables routine monitoring
- Reduces operational cost
- Improves reserve estimation reliability

The approach is particularly valuable for mature Niger Delta fields where frequent logging campaigns are economically impractical.

CONCLUSIONS

The findings reinforce the necessity of adopting compositional-aware reservoir characterization approaches in Niger Delta fields. By bridging the identified knowledge gaps particularly, the scarcity of vertically resolved compositional datasets and leveraging emerging technologies such as downhole fluid profiling and predictive model development for fluid contact movement assisted with fluid identification, operators can significantly improve the reliability of fluid contact prediction and optimize long-term field development strategies.

Field B exhibited the most significant API variation, ranging from 50° API in the gas cap to 20° API in deeper oil layers.

Overall, the study shows the following.

1. API gravity variation correlates strongly with compositional grading and contact movement.
2. Simulator-based API tracking offers a cost-effective surveillance alternative.
3. Integration with EOS-based compositional modeling enhances predictive capability.
4. The method improves reserves estimation accuracy and production planning.
5. Wider adoption in Niger Delta operations is recommended.

In this light, API gravity consistently decreases with depth, confirming gravity segregation and compositional grading in Niger Delta reservoirs.

Lighter hydrocarbons with higher API gravity are found in shallower sections, while deeper zones contain heavier oils.

REFERENCES

[1] AAPG. (2016). Fluid contact. Retrieved from American Association of Petroleum Geologists. Wiki Article. August 1.

[2] Aarre, V. (2007). Estimating 4D velocity changes and contact movement on the Norne Field. Offshore Technology Conference (OTC 19049). Houston, Texas: Schlumberger.

[3] Adebayo, P., Adeyemi, T., & Uchenna, S. (2019). API gravity-depth correlation for reservoir fluid characterization. Nigerian Journal of Petroleum Technology, 38(2), 201-215.

[4] Adedayo, T., & Uchenna, M. (2019). Development of simple correlation to evaluate formation volume factor for Nigerian crude oil. International Journal of Science and Research, 4(4), 45-55.

[5] Bath, P. V. (1983). Enhanced oil recovery in the North Sea. 11th World Petroleum Congress.

[6] Belery, P. A., & Da Silva. (1990). Gravity and thermal diffusion in hydrocarbon reservoirs. Third Chalk Research Program. Copenhagen.

[7] Chaback, J. (1992). Discussion of treatment of variations of composition with depth in gas-condensate reservoirs. SPERE, 157-158.

[8] Fred L. Goldsberry, W. I. (2001). Reservoir conformance: Tracking gas/water contacts via capillary shockwave fronts. SPE Annual Technical Conference and Exhibition. New Orleans: Society of Petroleum Engineers.

[9] Holt, T. L. (1983). The effect of gravity and temperature gradients on methane distribution in oil reservoirs. Unsolicited paper SPE 11761.

[10] Igwe, S. O., Onwumere, A. C., & Okoli, N. J. (2020). Integrating compositional grading into dynamic simulation for improved recovery

prediction. Journal of Petroleum Exploration and Production Technology, 10(12), 5131–5143.

[11] J. E. Paredes, Á. C.-P., & Lar, C. J. (2017). Methodology for fluid contact monitoring through surface API data. SPE Latin America and Caribbean Petroleum Engineering Conference. Buenos Aires.

[12] Li, J. (2010). Compositional distribution in volatile oil reservoir with compositional gradient. Xinjiang Petroleum Geology, 81-84.

[13] Nwankwo, C. D., Okeke, I. J., & Eke, P. U. (2022). Structural compartmentalization and its influence on pressure regimes and fluid communication in Niger Delta fields. Nigerian Journal of Petroleum Technology, 9(3), 65–79.

[14] Obiora, K. C., & Chukwu, L. N. (2022). Multi-phase fluid contact behavior and the impact of reservoir heterogeneity in Niger Delta oil fields. Journal of African Earth Sciences, 193, 104626.

[15] Oyelami, O., Adebisi, R., & Kalu, A. (2022). Sustainable field management strategies using API gravity and compositional surveillance in mature Niger Delta reservoirs. Energy Reports, 8, 10345–10360.

[16] Padua, K. O. (1997). Oil composition variation in a large deep-water field. Latin American and Caribbean Petroleum Engineering Conference. Brazil.

[17] Wang, W., Shengjun, D., Xinfei, H., Yuan, L., & Xiaolin, J. (2015). Study on impact of compositional gradient on volatile oil reservoir development.

[18] Zhou, J., Wang, L., & Fang, H. (2024). The role of gravity and temperature on hydrogen and hydrocarbon compositional grading in deep reservoirs. Energy Reports, 10, 1792–1807.